DISCLAIMER

INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

Contract No. DE-FC22-95BC14988

Utah Geological Survey (UGS), Salt Lake City, Utah 84114-6100

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Reporting Period: October 1 - December 31, 1997

Objectives

The primary objective of this project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced oil recovery technology in the Paradox basin, southeastern Utah. If this project can demonstrate technical and economic feasibility, the technique can be applied to about 100 additional small fields in the Paradox basin alone, and result in increased recovery of 150 to 200 million barrels of oil. This project is designed to characterize five shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation and choose the best candidate for a pilot demonstration project for either a waterflood or carbon dioxide-(CO_2-) flood project. The field demonstration, monitoring of field performance, and associated validation activities will take place in the Paradox basin within the Navajo Nation. The results of this project will be transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, and publication in newsletters and various technical or trade journals.

Summary of Technical Progress

Four activities continued this quarter as part of the geological and reservoir characterization of productive carbonate buildups in the Paradox basin: (1) geological reservoir characterization of project fields, (2) improved oil recovery assessment of Anasazi field, (3) reservoir engineering evaluation of Runway field, and (4) technology transfer.

Geological Reservoir Characterization of Project Fields

Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity as well as possible compartmentalization within each of the five project fields (Fig. 1). This study utilized representative core and modern geophysical logs to characterize and grade each of the five fields for suitability of enhanced recovery projects.

The typical vertical sequence or cycle of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response; an example is shown in Fig. 2. These sequences graphically include: (1) carbonate fabric, pore type, physical structures, texture, framework grains, and facies (as defined by Chidsey *et al.*[1-2]) described from core, (2) plotted porosity and permeability analysis from core plugs, and (3) gamma-ray and neutron-density curves from geophysical logs. The graphs can be used for identifying reservoir and non-reservoir rock, determining potential units suitable for water-and/or CO_2-flood projects, and comparing field to non-field areas.

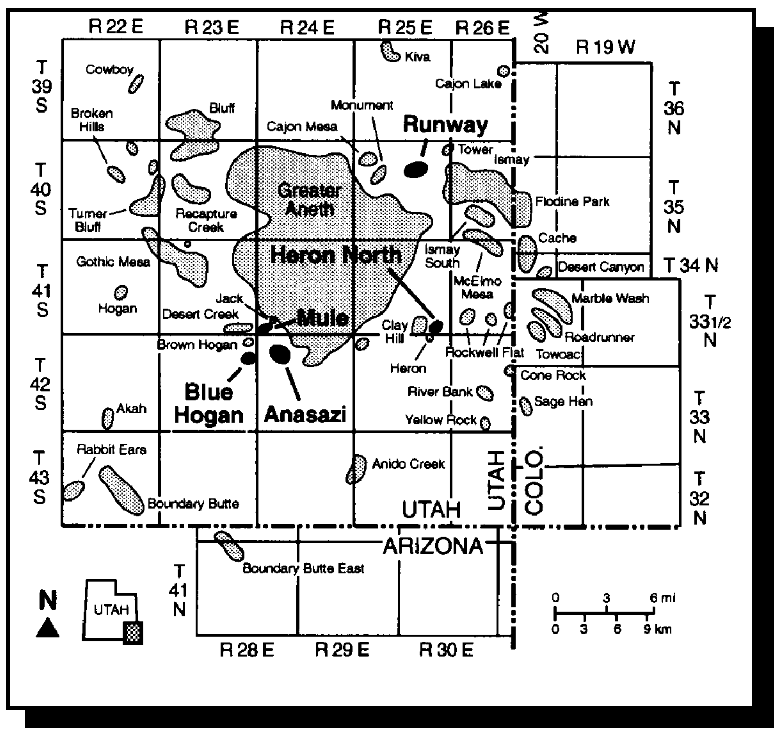
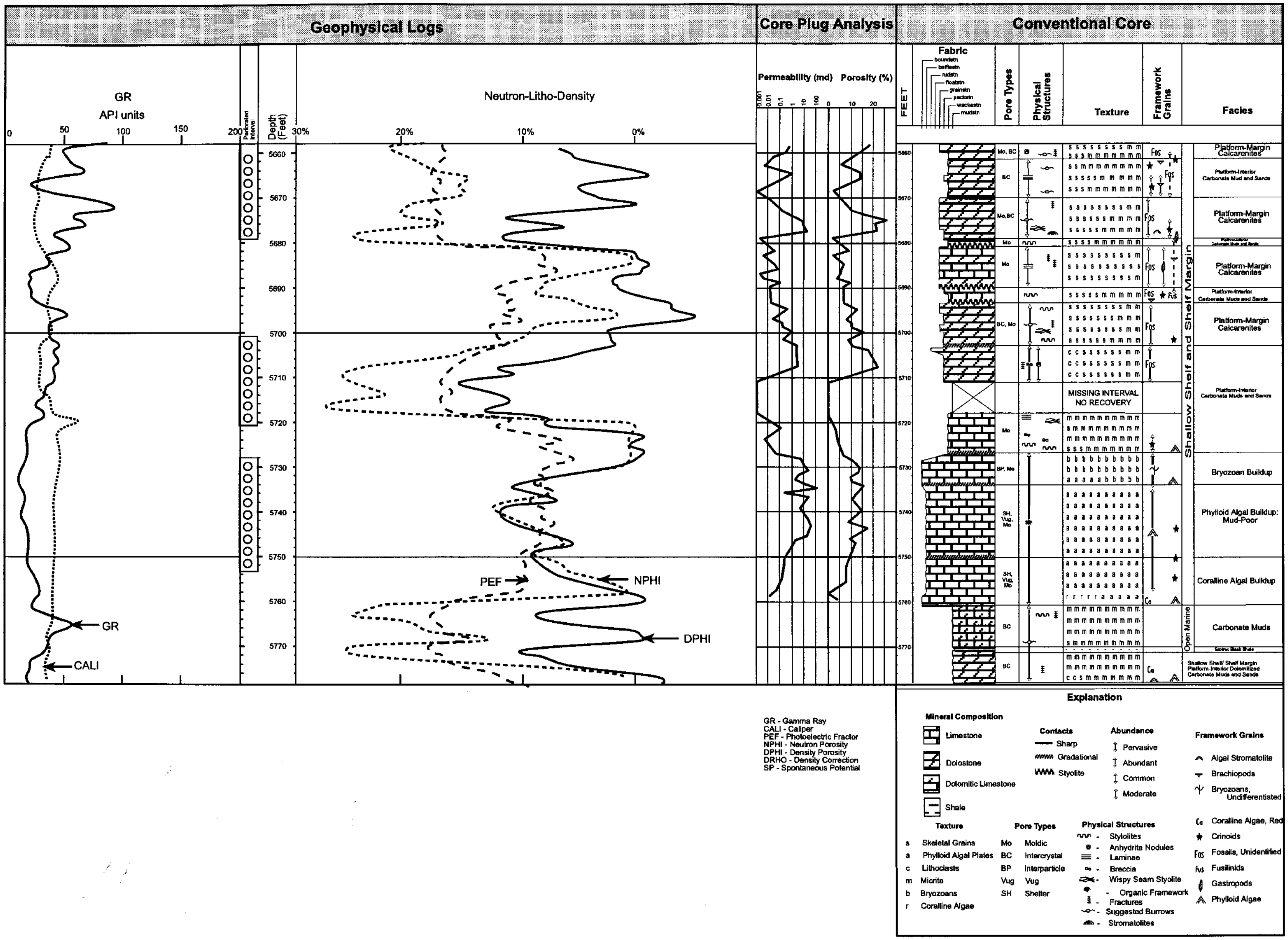


Fig. 1. Location of project fields (dark shaded areas with names in bold type) in the southwestern Paradox basin on the Navajo Nation, San Juan Co., Utah.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of each field can be an indicator of reservoir flow capacity, storage capacity, and potential for water-and/or CO_2-flooding. In order to determine the diagenetic histories of the various Desert Creek reservoirs, 50 representative samples were selected for geochemical analysis. Thin sections were also made of each sample for petrographic description. Typical geochemical and petrographic techniques that will be employed include: (1) epi-fluorescence and cathodoluminescence petrography for the sequence of diagenesis, (2) stable carbon and oxygen isotope analysis of diagenetic components such as cementing minerals


Geophysical Logs
Core Plug Analysis
Conventional Core
GR
API units
Neutron-Litho-Density
Depth (Feet)
Permeability (md)
Porosity (%)
Fabric
Pore Types
Physical Structures
Texture
Framework Grains
Facies
Platform-Margin Calcarenites
Platform-Interior Carbonate Mud and Sands
MISSING INTERVAL NO RECOVERY
Bryozoan Buildup
Phylloid Algal Buildup: Mud-Poor
Coralline Algal Buildup
Carbonate Muds
Shallow Shelf and Shelf Margin
Open Marine
PEF
NPHI
DPHI
GR
CALI
GR - Gamma Ray
CALI - Caliper
PEF - Photoelectric Fractor
NPHI - Neutron Porosity
DPHI - Density Porosity
DRHO - Density Correction
SP - Spontaneous Potential
Explanation
Mineral Composition
Limestone
Dolostone
Dolomitic Limestone
Shale
Contacts
Sharp
Gradational
Stylolite
Abundance
Pervasive
Abundant
Common
Moderate
Framework Grains
Algal Stromatolite
Brachiopods
Bryozoans, Undifferentiated
Coralline Algae, Red
Crinoids
Fossils, Unidentified
Fusilinids
Gastropods
Phylloid Algae
Texture
s Skeletal Grains
a Phylloid Algal Plates
c Lithoclasts
m Micrite
b Bryozoans
r Coralline Algae
Pore Types
Mo Moldic
BC Intercrystal
BP Interparticle
Vug Vug
SH Shelter
Physical Structures
Stylolites
Anhydrite Nodules
Laminae
Breccia
Wispy Seam Stylolite
Organic Framework
Fractures
Suggested Burrows
Stromatolites

and different generations of dolomites, (3) strontium isotopes for tracing the origin of fluids responsible for different diagenetic events, (4) scanning electron microscope analysis of various dolomites to determine reservoir quality of the dolomites as a function of diagenetic history, and (5) analysis of bitumen plugging pore throats. Each core was photographed (Fig. 3) and additional close-up photos were taken of: (1) typical moldic, vuggy, dolomitized, karst-brecciated, stylolitic as well as preserved primary porosity styles, (2) visible cement types, (3) sedimentary structures, and (4) pore plugging anhydrite and halite.

All depositional, diagenetic, and porosity information will be placed into the context of the production history to date of each field in order to construct a detailed overview for each enhanced recovery candidate. Of special interest will be the determination of the most effective pore systems for oil drainage versus storage.

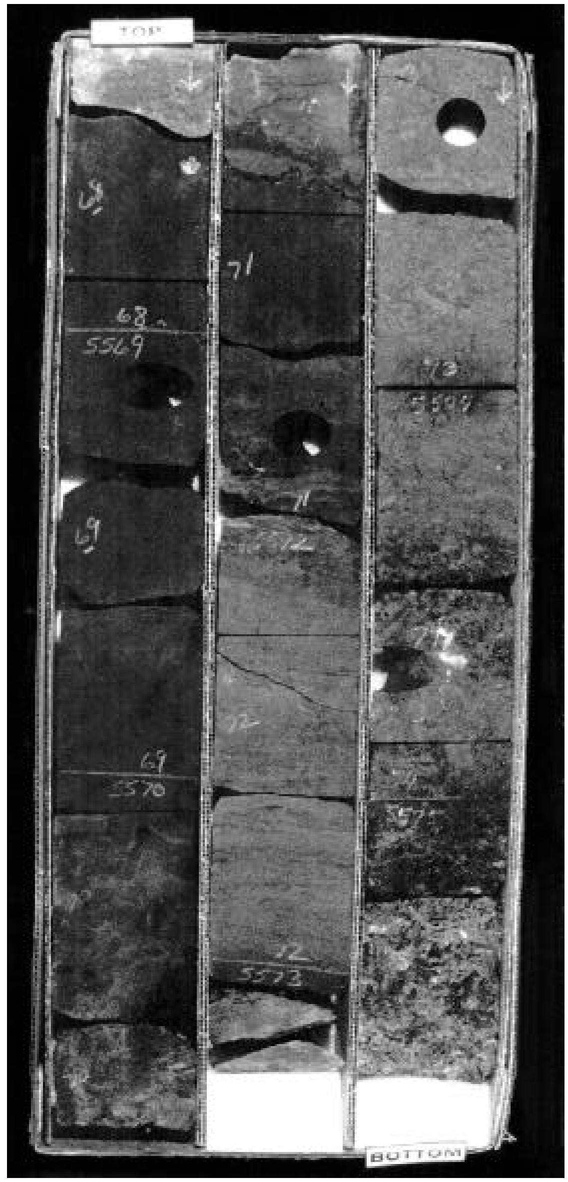


Fig. 3. Core photograph of the highly dolomitized, oil-saturated calcarenite section of the North Heron No. 35-C well, Heron North field, San Juan Co., Utah.

Improved Oil Recovery Assessment of Anasazi Field

The reservoir analysis for the Anasazi field (Fig. 1) required a field-scale reservoir simulator. Enhanced recovery through water-flooding and CO_2-flooding were evaluated using a compositional simulation. Variations in carbonate lithotypes, porosity, and permeability were incorporated into the simulation in order to accurately predict reservoir response.[2,3] History matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be confidently predicted.

The principal operating parameters and simulation related data in effect for the final two simulation prediction cases (A and B) were:

- CO_2 injection starts on January 1, 2000.
- Simulation case A uses an injection rate of 2.0 million standard cubic ft of gas per day (MMSCFGPD)/well and case B uses an injection rate of 4.0 MMSCFGPD/well. Injection was simulated through one well in each of the two mound lobes (Fig. 4).

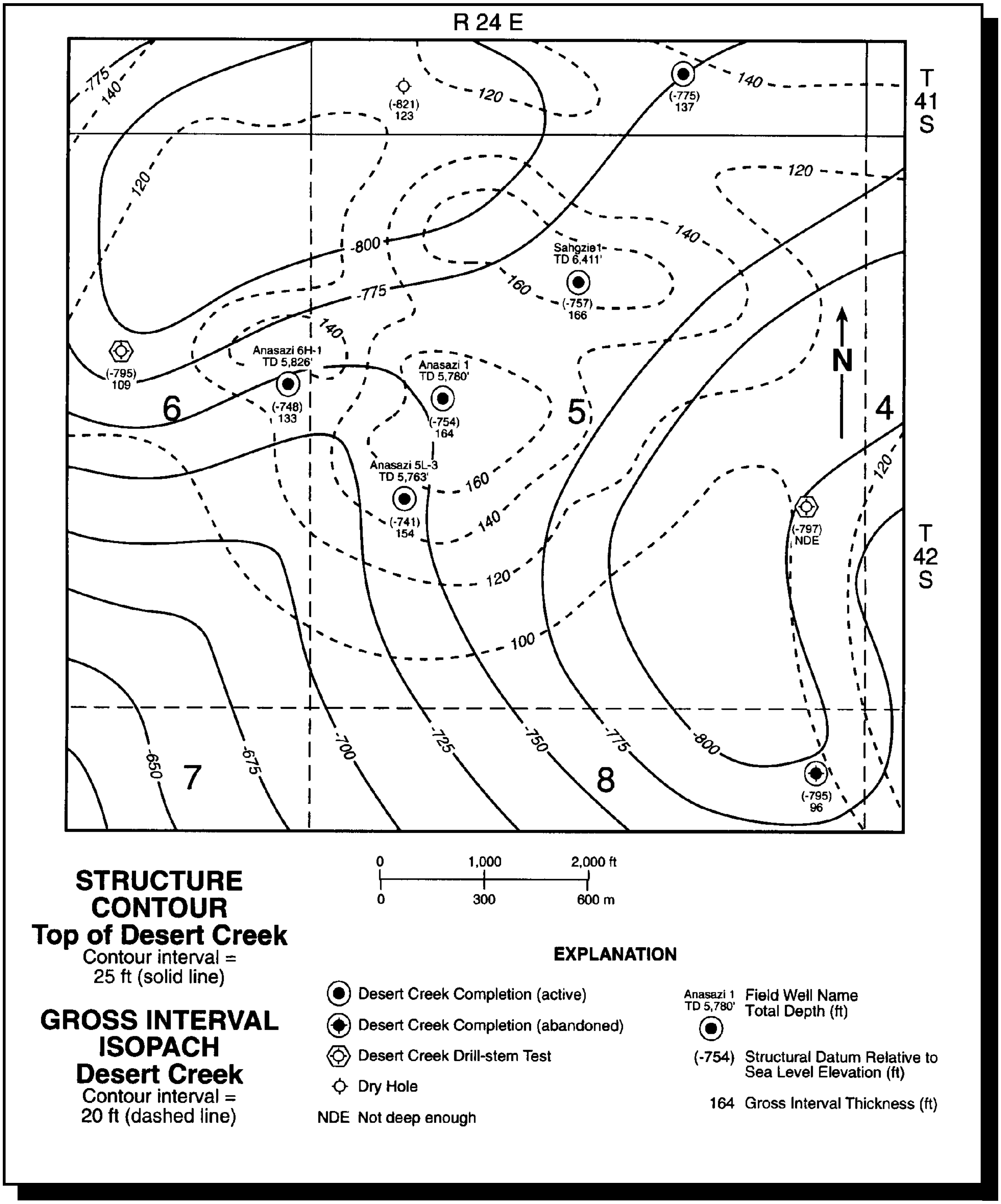


Fig. 4. Combined Desert Creek zone structure contour and gross interval isopach map, Anasazi field, San Juan Co., Utah.[4]

- Production wells Anasazi No. 1, Anasazi No. 5L-3, and Sahgzie No. 1 (Fig. 4) were allowed to produce at the rate in effect on January 1, 2000 during reservoir fill-up.

- Produced gas was recycled to reduce CO_2 make-up gas purchases. Thus, no conditioning was employed.

- CO_2 injection was continuous from the start of injection until January 1, 2012.

Table 1 summarizes relevant production/injection data for simulation prediction cases A and B. The data shows that for case A, the incremental oil recovery above primary was 951,000 bbls at January 1, 2012. This required injection of 17.5 billion standard cubic ft (BSCF) of CO_2 and produced gas and purchase of 10.1 BSCF of CO_2. Simulation prediction results indicate that a CO_2 injection rate of 2.0 MMSCFGPD/ well would not be sufficient to meet ongoing production needs of the operator (Harken Southwest Corporation) and generate acceptable economic returns. It would however, increase recovery by close to 1.0 million stock tank bbls (MMSTB) of oil over predicted primary recovery at January 1, 2012.

TABLE 1

Production/Injection Data for CO_2 Flood, Anasazi Field

Case	Cum Oil (MSTB)	Cum Gas (BSCF)	Incremental over Primary (MSTB)	Total Gas Inj. (BSCF)	Total CO_2 Purchase (BSCF)	Total Gas Recycled (BSCF)
Production / Injection at January 1, 2003						
A	2116	1.7	-78	4.4	4.2	0.2
B	2293	2.6	99	8.8	7.8	1.0
Production / Injection at January 1, 2006						
A	2385	2.4	-7	8.8	8.0	0.8
B	3302	9.4	910	17.5	9.8	7.7
Production / Injection at January 1, 2012						
A	3505	9.1	951	17.5	10.1	7.4
B	4208	25.2	1654	35.0	11.5	23.5

The data shows that for case B, the incremental oil recovery above primary was 1,654,000 bbls at January 1, 2012. This required injection of 35.0 BSCF of CO_2 and produced gas and purchase of 11.5 BSCF of CO_2. Specifically, using a 4.0 MMSCFGPD/well injection rate from two injectors, the CO_2 flood will recovery 4.21 MMSTB. This represents an increase of 1.65 MMSTB over predicted primary recovery at January 1, 2012. The projected 4.21 MMSTB represents more than

89% of the oil in the mound complex and 36.8% of the original oil in place in the total system modeled.

Production data and injection gas requirements, including CO_2 make-up purchases, from case B information were used to assess, from an economic standpoint, the financial merits of CO_2-flood with a 8.0 MMCFGPD total injection rate commencing January 1, 2000 are summarized using two options in Table 2. The economic assessment was conducted assuming the following conditions: (1) leased compressor (option 1 - $19,500/option 2 - $23,500 [same compressor with a different engine]), (2) CO_2 supply line construction using the minimum costs option ($825,000), (3) no gas processing, and (4) cost sharing by the U.S. Department of Energy (DOE). This assessment concludes that CO_2 flooding provides both an adequate flood response and an acceptable economic rate of return of 32% and a payout of 36 months. A discounted (10%) net present value of $5.9 million could be realized by implementing a CO_2 flood under the proposed conditions. Harken's capital outlay with DOE participation would be $1,493,000.

TABLE 2

Economic Performance Parameters for Low Injection Rate from Case B

Compressor Option	Before Tax NPV[1] (in thousands $)	Before Tax IRR[2] (%)	Payout Months	PI[3]
1	$5,930	32	36	10.4
2	$5,300	30	48	9.7

[1]NPV = net present value assuming a 10% cost of capital
[2]IRR = internal rate of return
[3]PI = profitability index

Reservoir Engineering Evaluation of Runway Field

The two main reservoir engineering work tasks for Runway field (Fig. 1) during the quarter were: (1) plotting of one-dimensional mechanistic simulation runs to identify CO_2 process minimum miscibility pressure and displacement - mass transfer mechanisms and (2) conducting history match runs of Runway field primary production history. CO_2-flood prediction case runs, using the the complete three-dimensional reservoir model, will commence next quarter.

Technology Transfer

T. C. Chidsey, Jr. presented a talk entitled *Heron North Field, Navajo Nation, San Juan County, Utah: A Case Study For Small Calcarenite Carbonate Reservoirs* at the monthly luncheon meeting of the Utah Geological Association on November 10, 1997.[5] The paper described the geologic trend for potentially hydrocarbon productive carbonate mound buildups within the Paradox basin.

The project home page on the UGS Internet web site (http://www.ugs.state.ut.us/paradox.htm) was updated with the latest quarterly technical report and project publications list.

References

1. T. C. Chidsey, Jr., D. E. Eby, and D. M. Lorenz, Geological and Reservoir Characterization of Small Shallow-shelf Carbonate Fields, Southern Paradox Basin, Utah, *Geology and Resources of the Paradox Basin* (A. C. Huffman, Jr., W. R. Lund, and L. H. Godwin, Eds.), Utah Geol. Assoc. Pub. 25: 39-56 (1996).

2. T. C. Chidsey, Jr., Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah, *Annual Report*, DOE Contract No. DE-FC22-95BC14988, DOE/BC/14988-9, August 1997.

3. D. M. Lorenz, W. E. Culham, T. C. Chidsey, Jr., and Kris Hartmann, Reservoir Modeling of the Anasazi Carbonate Mound, Paradox Basin, Utah [abs.]: *Amer. Assoc. of Petrol. Geol. Annual Convention, Official Program* 6: A71-72 (1997).

4. T. C. Chidsey, Jr., D. E. Eby, W. G. Groen, Kris Hartmann, and M. C. Watson, Anasazi Field, *Oil and Gas Fields of Utah* (B. G. Hill, and S. R. Bereskin, Eds.), Utah Geol. Assoc. Pub. 22 (Second Edition): non-paginated (1996).

5. T. C. Chidsey, Jr., and D. E. Eby, Heron North Field, Navajo Nation, San Juan County, Utah - A Case Study for Small Calcarenite Carbonate Buildups [abs.]: *Amer. Assoc. of Petrol. Geol. Bull.* 81 (7): 1220 (1997).